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Xu

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(54) **SYSTEM AND METHOD FOR SPREAD SPECTRUM BASED DRILL PIPE COMMUNICATIONS**

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Related U.S. Application Data

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(51) **Int. Cl.**

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E21B 47/12	(2012.01)
E21B 47/14	(2006.01)
E21B 47/16	(2006.01)
H04B 1/69	(2011.01)

(52) **U.S. Cl.**

CPC ***E21B 47/16*** (2013.01); ***E21B 47/00*** (2013.01); ***E21B 47/12*** (2013.01); ***E21B 47/14*** (2013.01); ***H04B 1/69*** (2013.01)

(58) **Field of Classification Search**

CPC E21B 47/00; E21B 47/12; E21B 47/14; E21B 47/16; H04B 1/69; H04B 2001/6916

USPC 340/853.2, 854.3, 854.4, 855.4, 855.7, 340/856.4; 367/81, 82; 375/130, 136, 147, 375/150, 240.21, 316, 346

See application file for complete search history.

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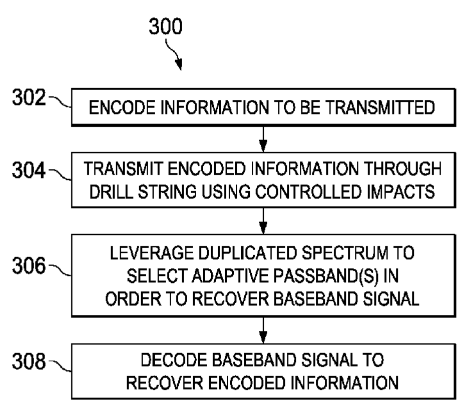
(57) **ABSTRACT**

A system and method are provided for communicating in a borehole. In one example, the method includes receiving a baseband signal transmitted through a drill string using a plurality of elastic waves, where a spectrum of the baseband signal is duplicated after transmission due to oversampling. At least one passband is selected in order to recover the baseband signal from the duplicated spectrum. The baseband signal is decoded to recover a bit stream contained within the baseband signal.

15 Claims, 13 Drawing Sheets



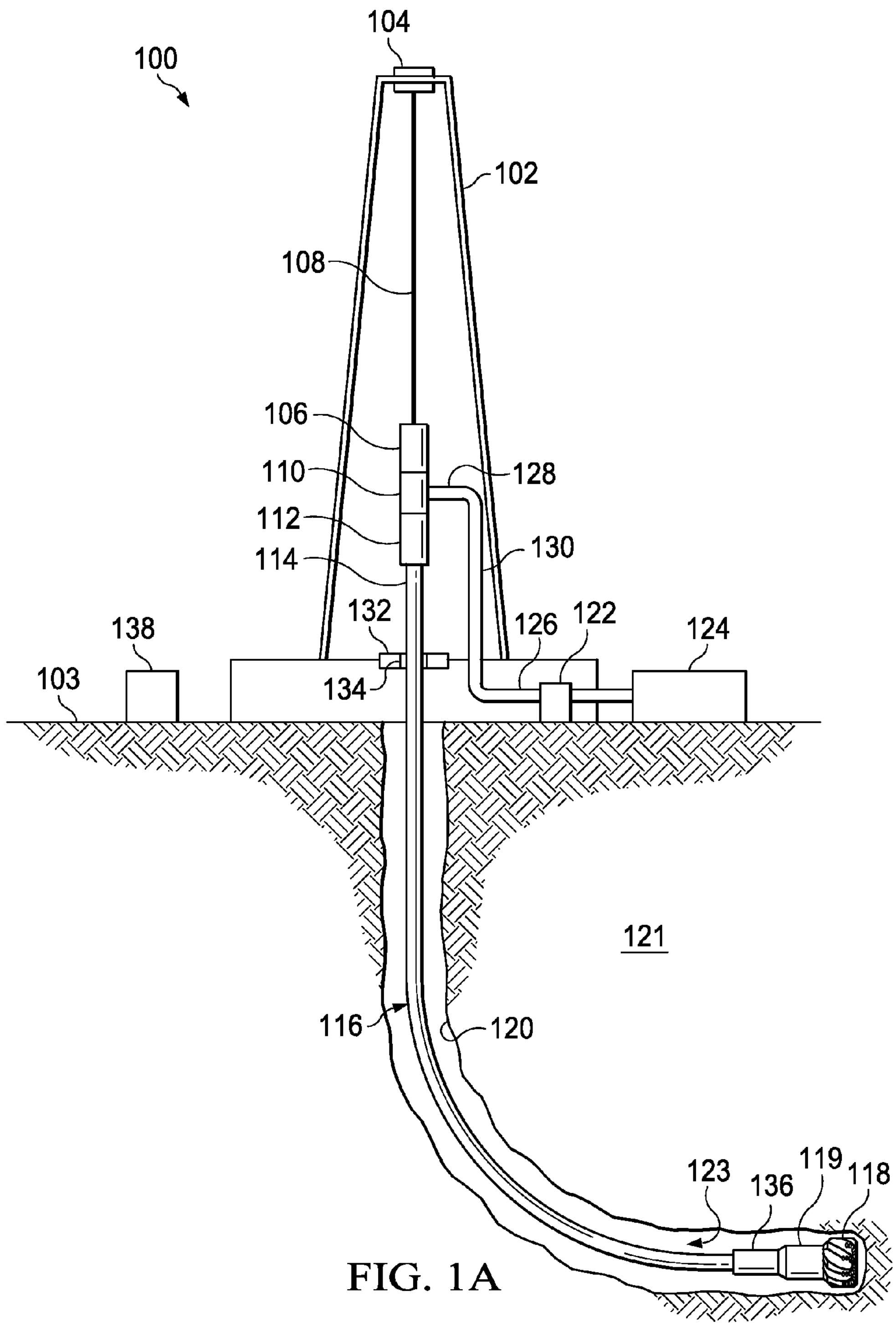

104
100
102
108
106
110
128
112
114
130
132
126
122
124
138
103
134
121
116
120
123
119
136
118

FIG. 1A

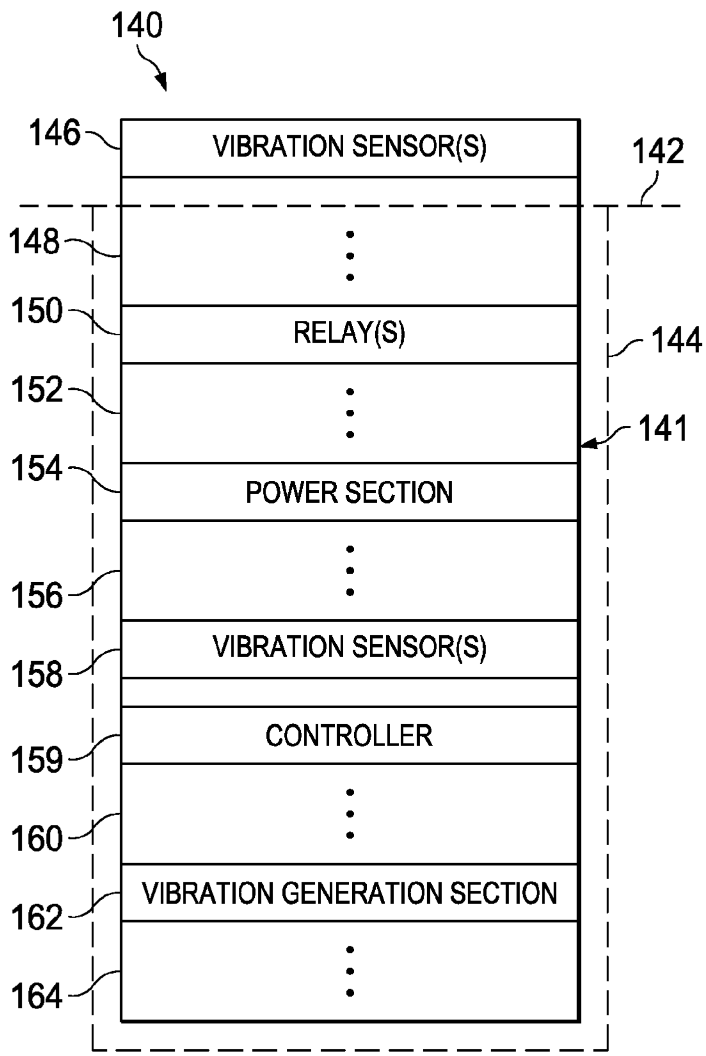

140
146
VIBRATION SENSOR(S)
142
148
150
RELAY(S)
144
152
141
154
POWER SECTION
156
VIBRATION SENSOR(S)
158
CONTROLLER
159
160
VIBRATION GENERATION SECTION
162
164

FIG. 1B

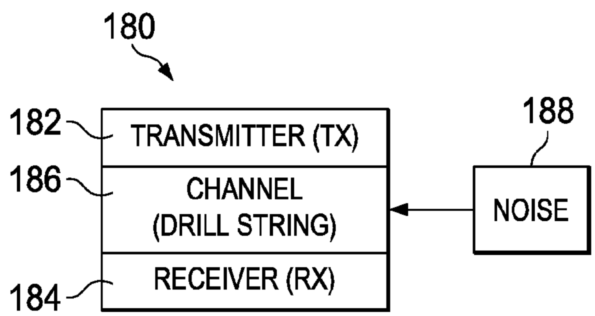

180
182
TRANSMITTER (TX)
186
CHANNEL
(DRILL STRING)
188
NOISE
RECEIVER (RX)
184

FIG. 1C

FIG. 2A

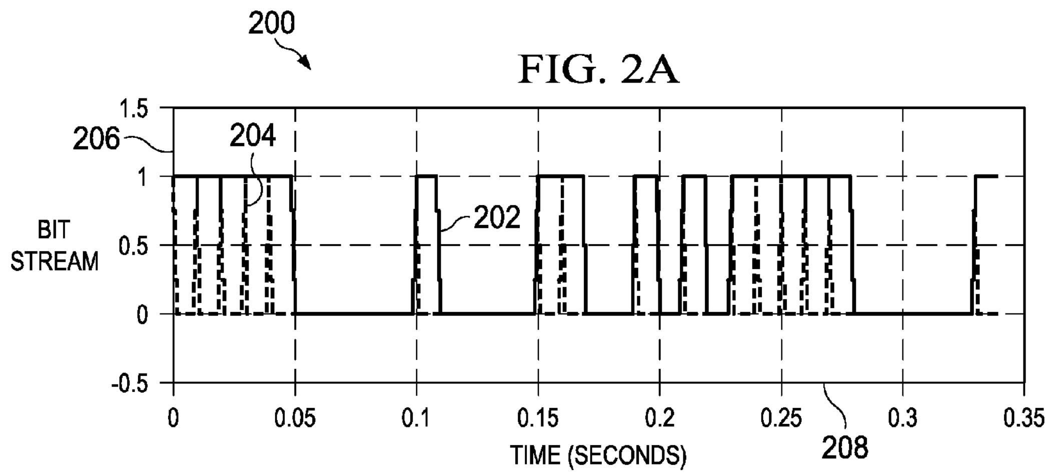
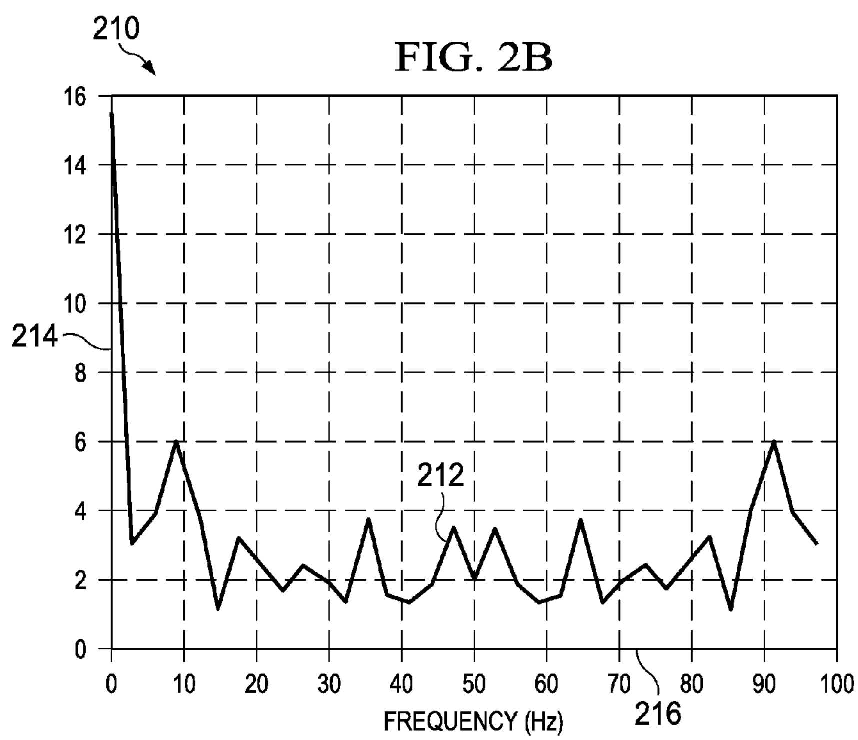
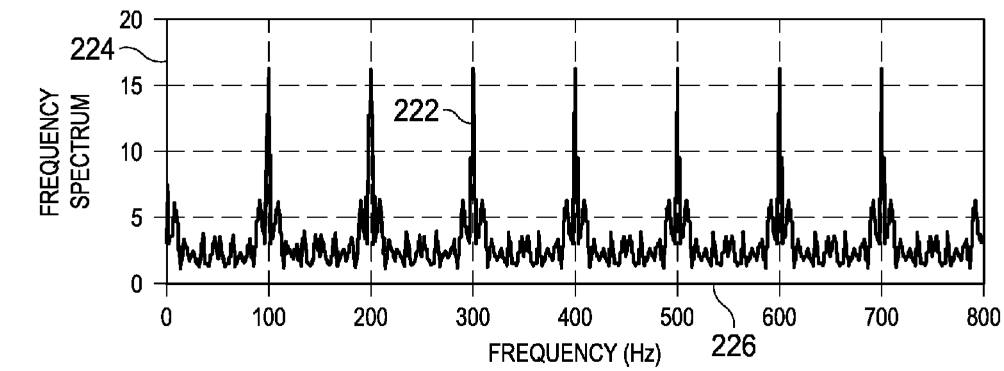

200
206
204
202
1.5
1
0.5
0
-0.5
BIT
STREAM
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
TIME (SECONDS)
208

FIG. 2B


210
214
212
16
14
12
10
8
6
4
2
0
0
10
20
30
40
50
60
70
80
90
100
FREQUENCY (Hz)
216

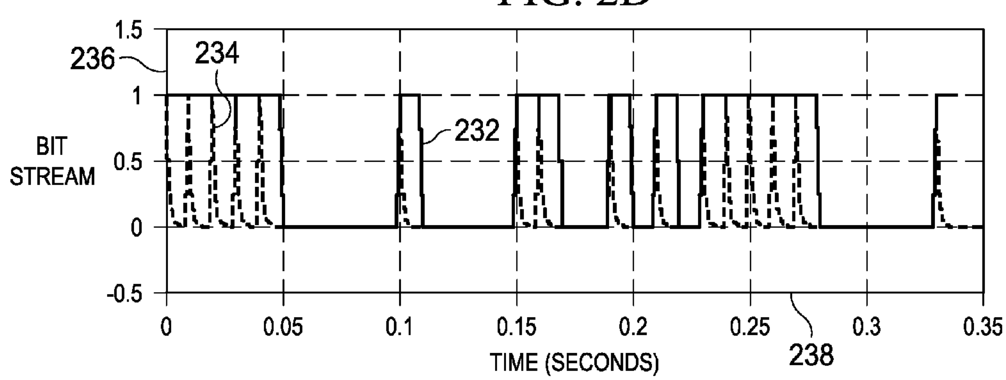
220

FIG. 2C



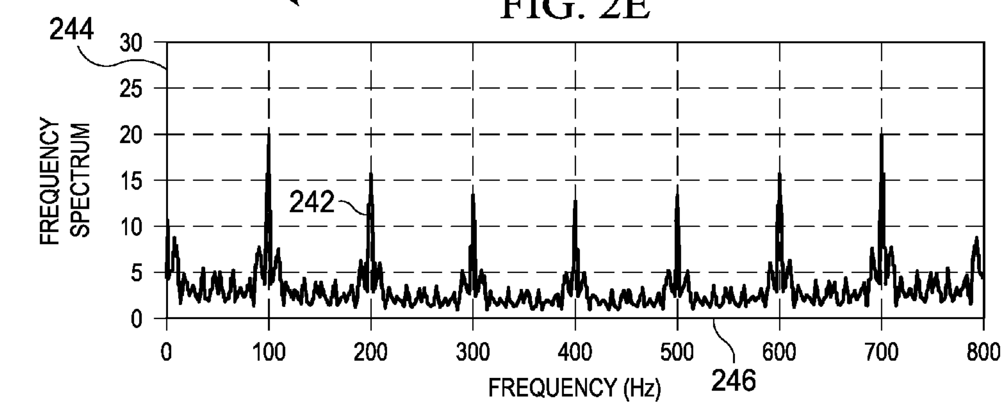
230

FIG. 2D



240

FIG. 2E



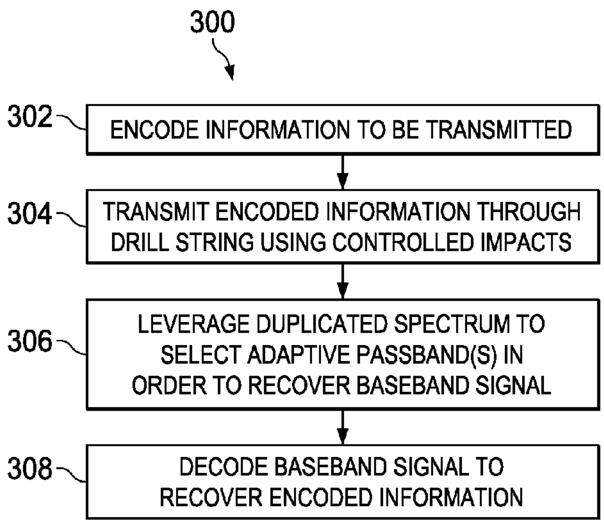

300
302
ENCODE INFORMATION TO BE TRANSMITTED
304
TRANSMIT ENCODED INFORMATION THROUGH DRILL STRING USING CONTROLLED IMPACTS
306
LEVERAGE DUPLICATED SPECTRUM TO SELECT ADAPTIVE PASSBAND(S) IN ORDER TO RECOVER BASEBAND SIGNAL
308
DECODE BASEBAND SIGNAL TO RECOVER ENCODED INFORMATION

FIG. 3

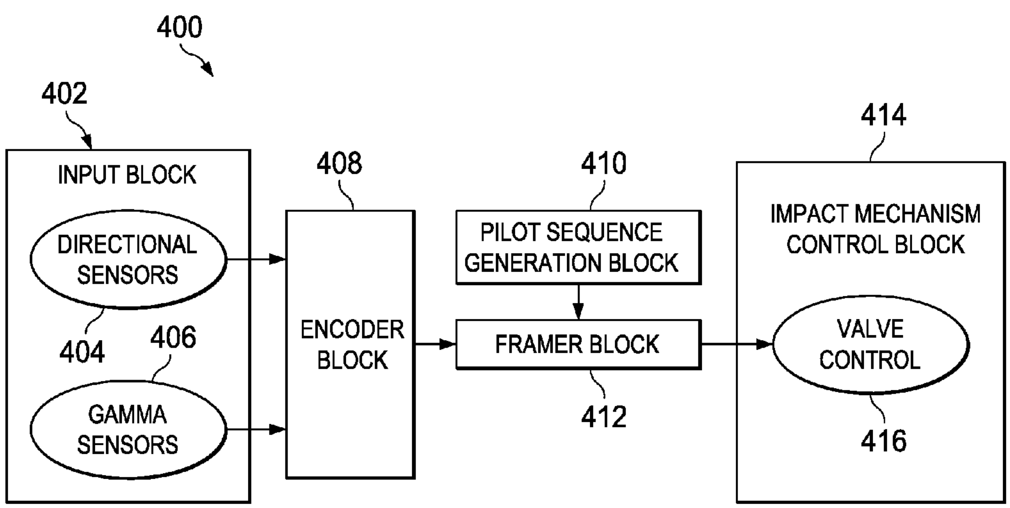

400
402
INPUT BLOCK
DIRECTIONAL SENSORS
404
406
GAMMA SENSORS
408
ENCODER BLOCK
410
PILOT SEQUENCE GENERATION BLOCK
FRAMER BLOCK
412
414
IMPACT MECHANISM CONTROL BLOCK
VALVE CONTROL
416

FIG. 4

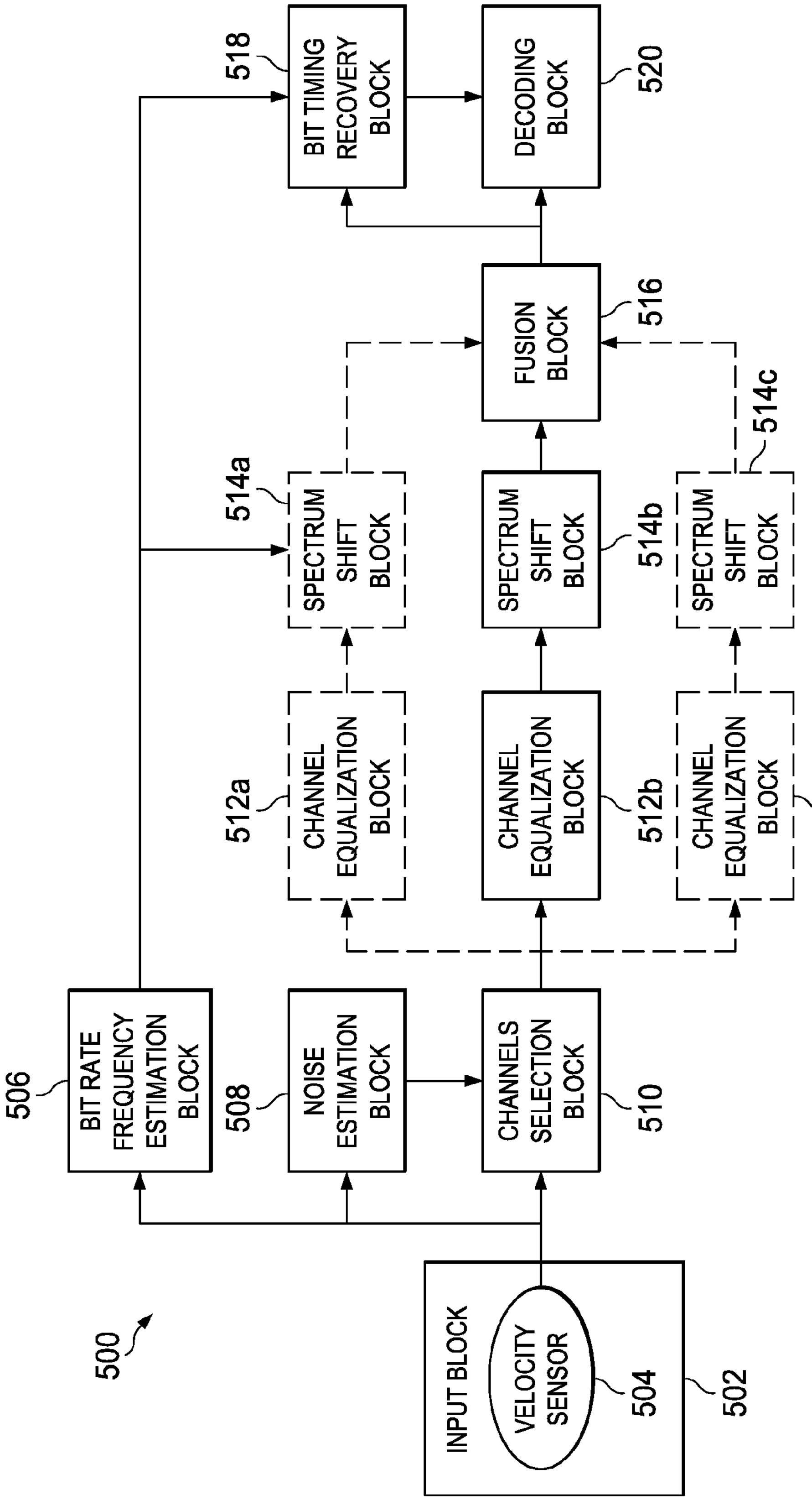

500
INPUT BLOCK
VELOCITY SENSOR
504
502
506
BIT RATE FREQUENCY ESTIMATION BLOCK
508
NOISE ESTIMATION BLOCK
CHANNELS SELECTION BLOCK
510
512a
CHANNEL EQUALIZATION BLOCK
CHANNEL EQUALIZATION BLOCK
512b
CHANNEL EQUALIZATION BLOCK
512c
514a
SPECTRUM SHIFT BLOCK
SPECTRUM SHIFT BLOCK
514b
SPECTRUM SHIFT BLOCK
514c
FUSION BLOCK
516
518
BIT TIMING RECOVERY BLOCK
DECODING BLOCK
520

FIG. 5

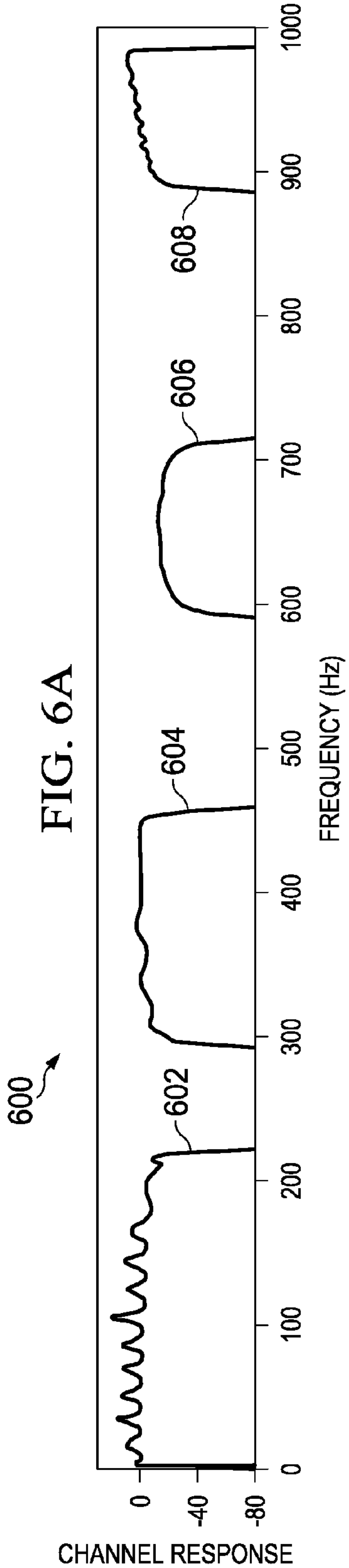

600
602
604
606
608
0
-40
-80
CHANNEL RESPONSE
0
100
200
300
400
500
600
700
800
900
1000
FREQUENCY (Hz)

FIG. 6A

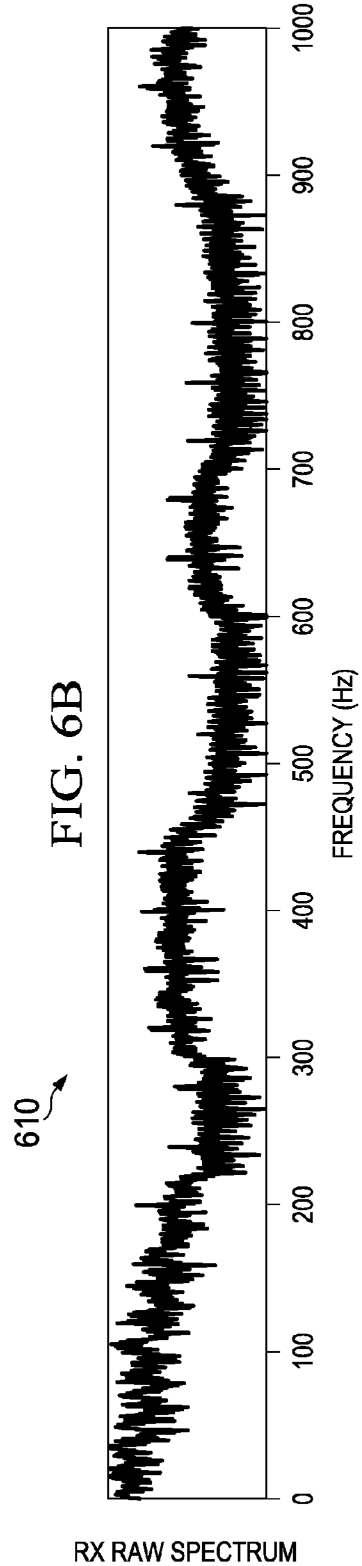

610
RX RAW SPECTRUM
0
100
200
300
400
500
600
700
800
900
1000
FREQUENCY (Hz)

FIG. 6B

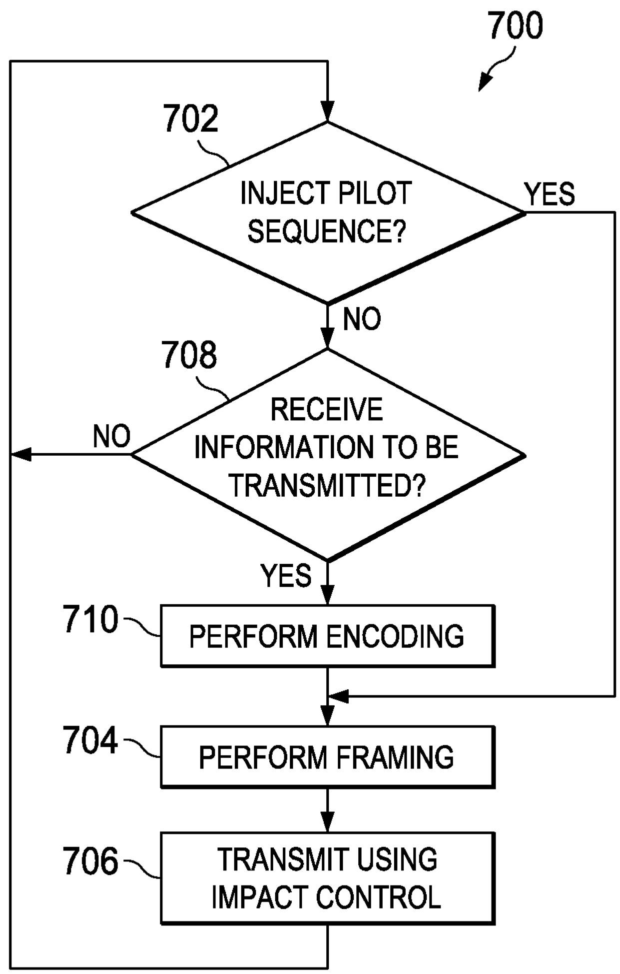
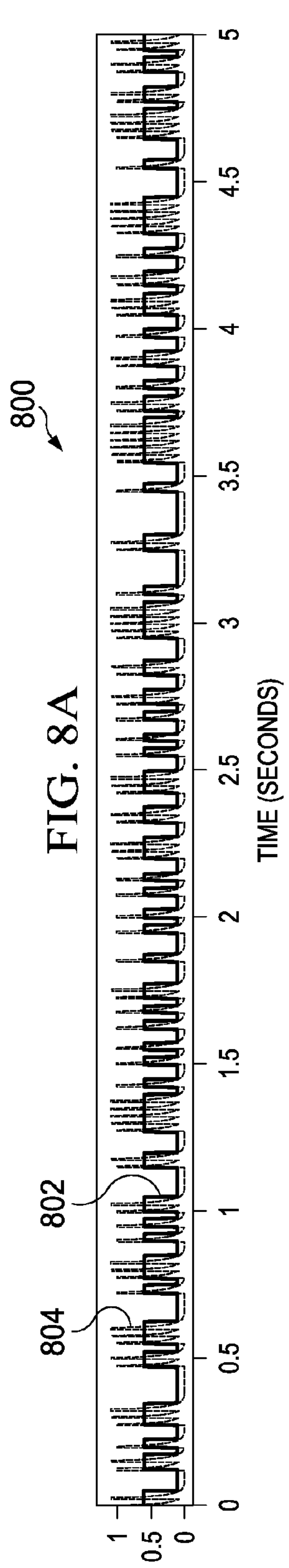
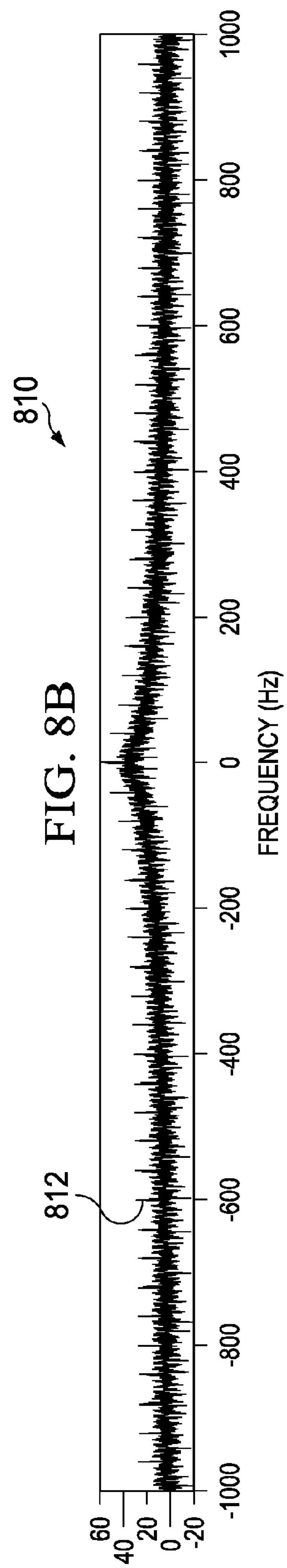

700
702
INJECT PILOT SEQUENCE?
YES
NO
708
RECEIVE INFORMATION TO BE TRANSMITTED?
NO
YES
710
PERFORM ENCODING
704
PERFORM FRAMING
706
TRANSMIT USING IMPACT CONTROL

FIG. 7



800
802
804
1
0.5
0
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
TIME (SECONDS)

FIG. 8A



810
812
60
40
20
0
-20
-1000
-800
-600
-400
-200
0
200
400
600
800
1000
FREQUENCY (Hz)

FIG. 8B

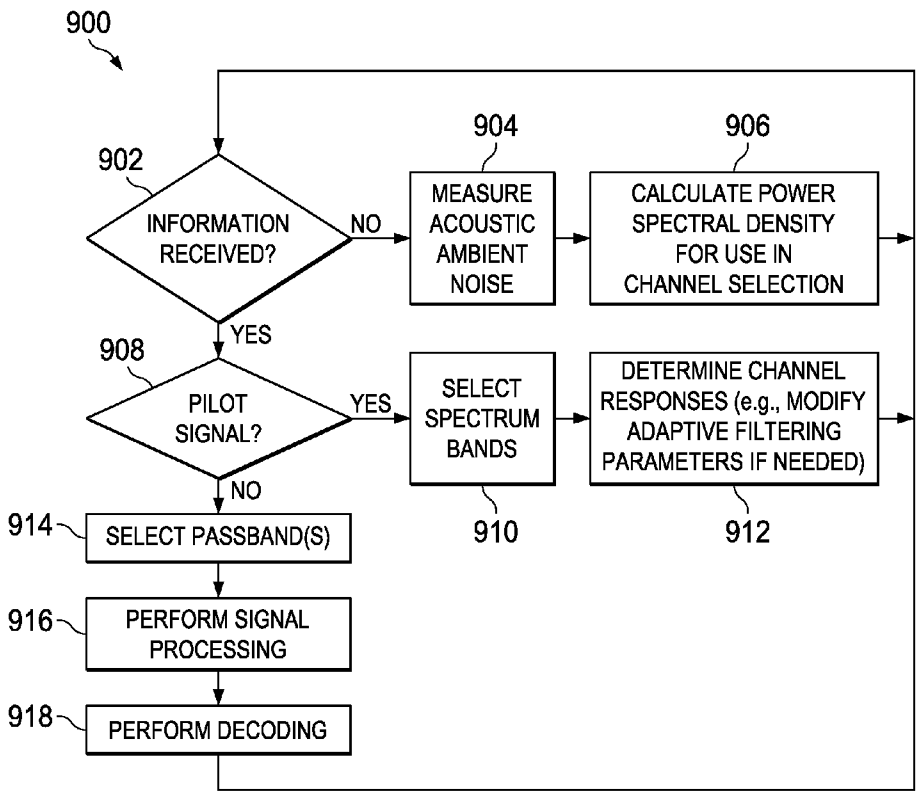

900
902
INFORMATION RECEIVED?
NO
904
MEASURE ACOUSTIC AMBIENT NOISE
906
CALCULATE POWER SPECTRAL DENSITY FOR USE IN CHANNEL SELECTION
YES
908
PILOT SIGNAL?
YES
SELECT SPECTRUM BANDS
910
DETERMINE CHANNEL RESPONSES (e.g., MODIFY ADAPTIVE FILTERING PARAMETERS IF NEEDED)
912
NO
914
SELECT PASSBAND(S)
916
PERFORM SIGNAL PROCESSING
918
PERFORM DECODING

FIG. 9

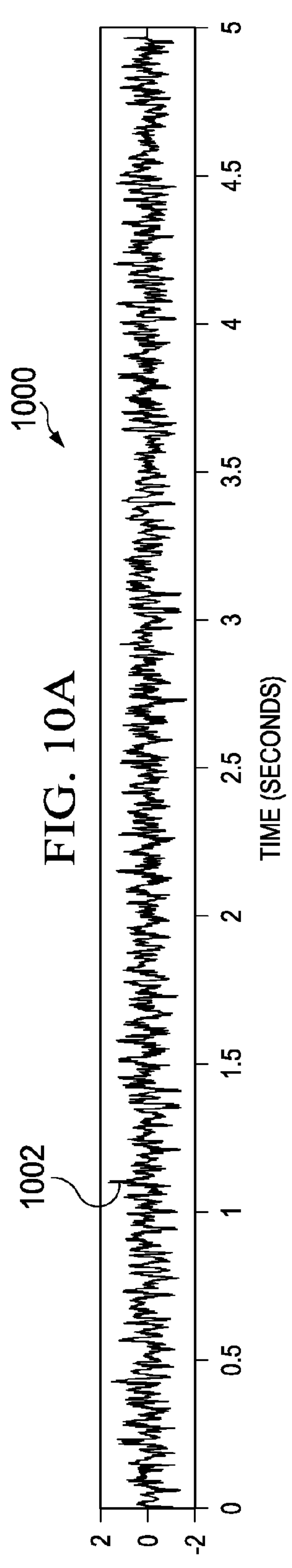


FIG. 10A

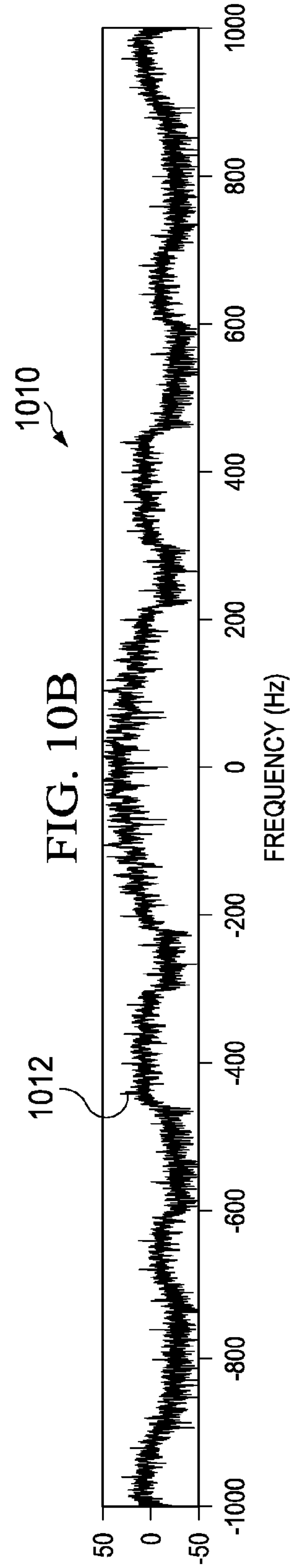


FIG. 10B

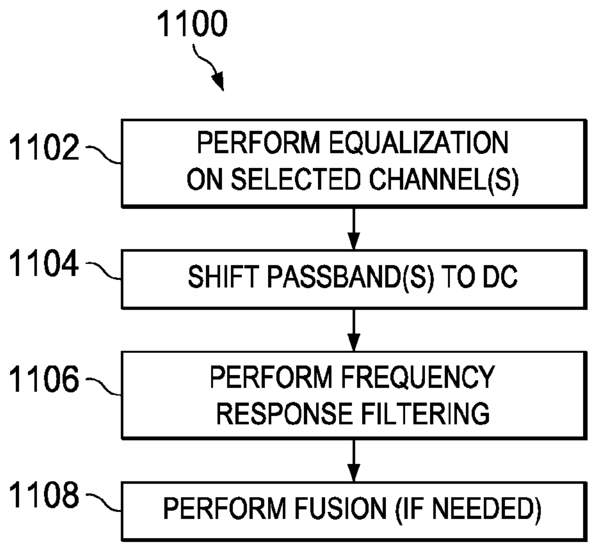

1100
1102
PERFORM EQUALIZATION ON SELECTED CHANNEL(S)
1104
SHIFT PASSBAND(S) TO DC
1106
PERFORM FREQUENCY RESPONSE FILTERING
1108
PERFORM FUSION (IF NEEDED)

FIG. 11

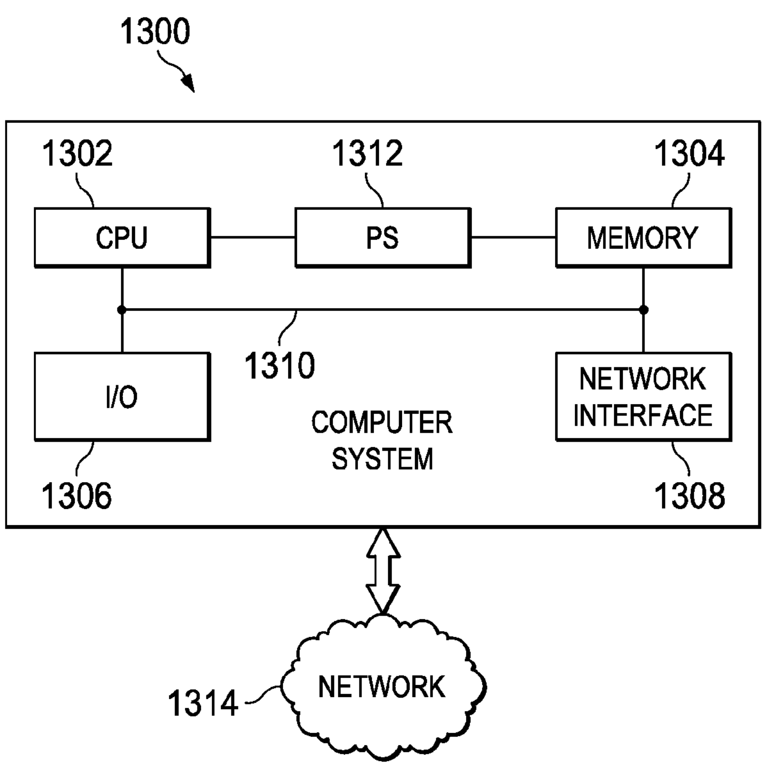

1300
1302
CPU
1312
PS
1304
MEMORY
1310
I/O
COMPUTER SYSTEM
NETWORK INTERFACE
1306
1308
1314
NETWORK

FIG. 13

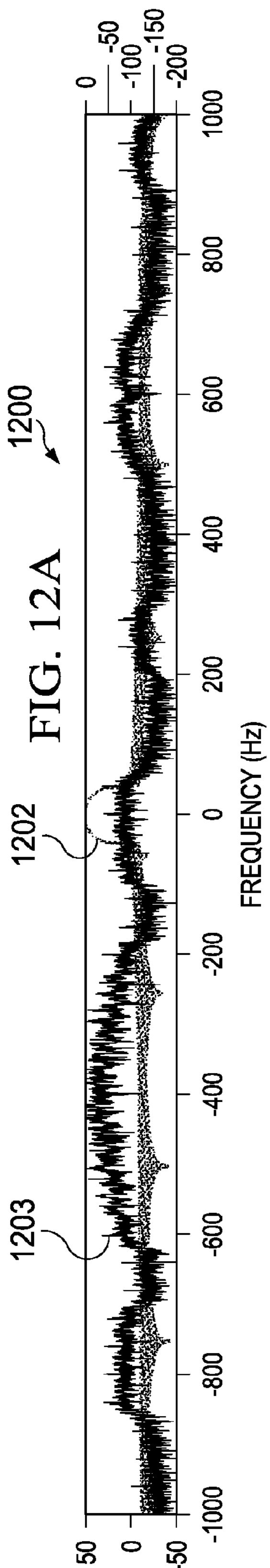


FIG. 12A

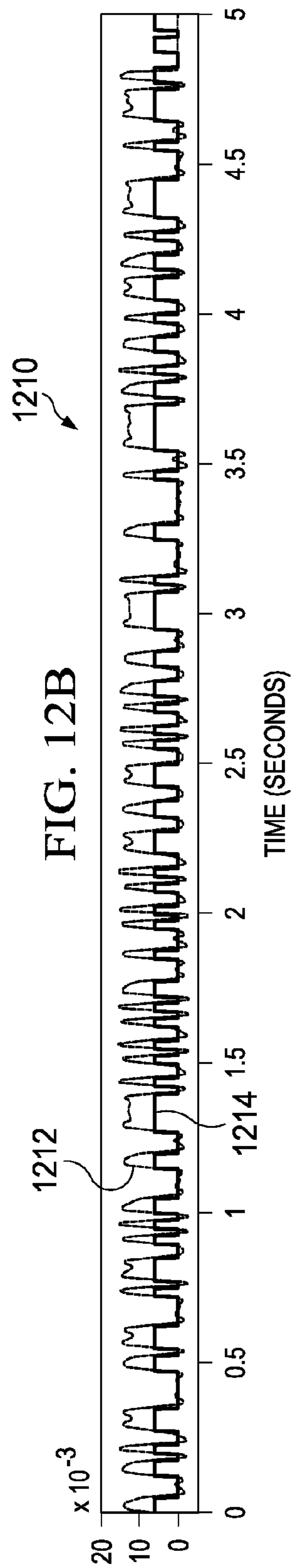


FIG. 12B

SYSTEM AND METHOD FOR SPREAD SPECTRUM BASED DRILL PIPE COMMUNICATIONS

CROSS-REFERENCE TO RELATED APPLICATIONS

This application claims the benefit of U.S. Provisional No. 61/913,648, filed Dec. 9, 2013, and entitled SYSTEM AND METHOD FOR SPREAD SPECTRUM BASED DRILL PIPE COMMUNICATIONS, which is hereby incorporated by reference in its entirety.

This application is related to U.S. patent application Ser. No. 14/145,044, filed Dec. 31, 2013, entitled SYSTEM AND METHOD FOR USING CONTROLLED VIBRATIONS FOR BOREHOLE COMMUNICATIONS, which is a continuation of U.S. patent application Ser. No. 14/010,259, filed Aug. 26, 2013, entitled SYSTEM AND METHOD FOR DRILLING HAMMER COMMUNICATION, FORMATION EVALUATION AND DRILLING OPTIMIZATION, which is a continuation of U.S. patent application Ser. No. 13/752,112, filed Jan. 28, 2013, entitled SYSTEM AND METHOD FOR DRILLING HAMMER COMMUNICATION, FORMATION EVALUATION AND DRILLING OPTIMIZATION, now U.S. Pat. No. 8,517,093, issued Aug. 27, 2013, which claims benefit of U.S. Provisional Application No. 61/693,848, filed Aug. 28, 2012, entitled SYSTEM AND METHOD FOR DRILLING HAMMER COMMUNICATION AND FORMATION EVALUATION USING MAGNETORHEOLOGICAL FLUID VALVE ASSEMBLY, and to U.S. Provisional Application No. 61/644,701, filed May 9, 2012, entitled SYSTEM AND METHOD FOR DRILLING HAMMER COMMUNICATION AND FORMATION EVALUATION, all of which are incorporated by reference herein in their entirety.

TECHNICAL FIELD

The following disclosure relates to directional and conventional drilling.

BACKGROUND

Drilling a borehole for the extraction of minerals has become an increasingly complicated operation due to the increased depth and complexity of many boreholes, including the complexity added by directional drilling. Drilling is an expensive operation and errors in drilling add to the cost and, in some cases, drilling errors may permanently lower the output of a well for years into the future. Current technologies and methods do not adequately address the complicated nature of drilling. Accordingly, what is needed are a system and method to improve drilling operations.

BRIEF DESCRIPTION OF THE DRAWINGS

For a more complete understanding, reference is now made to the following description taken in conjunction with the accompanying Drawings in which:

FIG. **1**A illustrates an environment within which various aspects of the present disclosure may be implemented;

FIG. **1**B illustrates one embodiment of a system that may be used to create vibrations within an environment such as the environment of FIG. **1**A;

FIG. **1**C illustrates one embodiment of the environment of FIG. **1**A from a communications perspective;

FIG. **2**A illustrates embodiments of a digital signal and a corresponding baseband signal;

FIG. **2**B illustrates one embodiment of a spectrum of the baseband signal of FIG. **2**A;

FIG. **2**C illustrates one embodiment of the spectrum of FIG. **2**B after duplication due to reflection within the drill string;

FIGS. **2**D and **2**E illustrate alternative embodiments of FIGS. **2**A and **2**C, respectively;

FIG. **3** illustrates a flow chart of one embodiment of a method that may be used within the environment of FIG. **1**C for communications;

FIG. **4** illustrates one embodiment of a transmitter that may be used within the environment of FIG. **1**C;

FIG. **5** illustrates one embodiment of a receiver that may be used within the environment of FIG. **1**C;

FIG. **6**A illustrates one embodiment of a channel response showing interleaved pass-bands and stop-bands;

FIG. **6**B illustrates one embodiment of a received raw frequency spectrum corresponding to the channel response of FIG. **6**A;

FIG. **7** illustrates a flow chart of one embodiment of a method that may be used with a transmitter such as the transmitter of FIG. **4**;

FIG. **8**A illustrates embodiments of a digital waveform and a corresponding baseband waveform;

FIG. **8**B illustrates one embodiment of a spectrum of the transmitted baseband waveform of FIG. **8**A;

FIG. **9** illustrates a flow chart of one embodiment of a method that may be used with a receiver such as the receiver of FIG. **5**;

FIG. **10**A illustrates one embodiment of a raw received waveform of the baseband waveform of FIG. **8**A;

FIG. **10**B illustrates one embodiment of a spectrum of the received baseband waveform of FIG. **10**A;

FIG. **11** illustrates a flow chart of a more detailed embodiment of a processing step of the method of FIG. **9**;

FIG. **12**A illustrates one embodiment of the spectrum of FIG. **10**B after being shifted by 400 Hz and also illustrates a filter positioned with respect to the shifted spectrum;

FIG. **12**B illustrates one embodiment of the baseband waveform after the filter of FIG. **12**A is applied and a digital waveform that corresponds to the baseband waveform; and

FIG. **13** illustrates one embodiment of a computer system that may be used within the environment of FIG. **1**A.

DETAILED DESCRIPTION

Referring now to the drawings, wherein like reference numbers are used herein to designate like elements throughout, the various views and embodiments of a system and method for spread spectrum based drill pipe communications are illustrated and described, and other possible embodiments are described. The figures are not necessarily drawn to scale, and in some instances the drawings have been exaggerated and/or simplified in places for illustrative purposes only. One of ordinary skill in the art will appreciate the many possible applications and variations based on the following examples of possible embodiments.

During the drilling of a borehole, it is generally desirable to receive data relating to the performance of the bit and other downhole components, as well as other measurements such as the orientation of the toolface. While such data may be obtained via downhole sensors, the data should be communicated to the surface at some point. However, data communication from downhole sensors to the surface tends to be excessively slow using current mud pulse and electromagnetic (EM) methods. For example, data rates may be in the single digit baud rates, which may mean that updates occur at a minimum interval (e.g., ten seconds). It is understood that various factors may affect the actual baud rate, such depth, flow rate, fluid density, and fluid type.

The relatively slow communication rate presents a challenge as advances in drilling technology increase the rate of penetration (ROP) that is possible. As drilling speed increases, more downhole sensor information is needed and needed more quickly in order to geosteer horizontal wells at higher speeds. For example, geologists may desire a minimum of one gamma reading per foot in complicated wells. If the drilling speed relative to the communication rate is such that there is only one reading every three to five feet, which may be fine for simple wells, the bit may have to be backed up and part of the borehole re-logged more slowly to get the desired one reading per foot. Accordingly, the drilling industry is facing the possibility of having to slow down drilling speeds in order to gain enough logging information to be able to make steering decisions.

This problem is further exacerbated by the desire for even more sensor information from downhole. As mud pulse and EM telemetry are serial channels, adding additional sensor information makes the communication problem worse. For example, if the current data rate enables a gamma reading to be sent to the surface every ten seconds via mud pulse, adding additional sensor information that must be sent along the same channel means that the ten second interval between gamma readings will increase unless the gamma reading data is prioritized. If the gamma reading data is prioritized, then other information will be further delayed. Another method for increased throughput is to use lower resolution data that, although the throughput is increased, provides less detailed data.

One possible approach uses wired pipe (e.g., pipe having conductive wiring and interconnects on either end), which may be problematic because each piece of the drill string has to be wired and has to function properly. For example, for a twenty thousand foot horizontal well, this means approximately six hundred connections have to be made and all have to function properly for downhole to surface communication to occur. While this approach provides a fast data transfer rate, it may be unreliable because of the requirement that each component work and a single break in the chain may render it useless. Furthermore, it may not be industry compatible with other downhole tools that may be available such as drilling jars, stabilizers, and other tools that may be connected in the drill string.

Another possible approach is to put more electronics (e.g., computers) downhole so that more decisions are made downhole. This minimizes the amount of data that needs to be transferred to the surface, and so addresses the problem from a data aspect rather than the actual transfer speed. However, this approach generally has to deal with high heat and vibration issues downhole that can destroy electronics and also puts more high cost electronics at risk, which increases cost if they are lost or damaged. Furthermore, if something goes wrong downhole, it can be difficult to determine what decisions were made, whether a particular decision was made correctly or incorrectly, and how to fix an incorrect decision.

Vibration based communications within a borehole typically rely on an oscillator that is configured to produce the vibrations and a transducer that is configured to detect the vibrations produced by the oscillator. However, the downhole power source for the oscillator is often limited and does not supply much power. Accordingly, the vibrations produced by the oscillator are fairly weak and lack the energy needed to travel very far up the drill string. Furthermore, drill strings typically have dampening built in at certain points inherently (e.g., the large amount of rubber contained in the power section stator) and the threaded connections may provide additional dampening, all of which further limit the distance the vibrations can travel.

Referring to FIG. **1**A, one embodiment of an environment **100** is illustrated in which various configurations of vibration creation and/or control functionality may be used to provide frequency tuning, formation evaluation, improvements in rate of penetration (ROP), high speed data communication, friction reduction, and/or other benefits. Although the environment **100** is a drilling environment that is described with a top drive drilling system, it is understood that other embodiments may include other drilling systems, such as rotary table systems.

In the present example, the environment **100** includes a derrick **102** on a surface **103**. The derrick **102** includes a crown block **104**. A traveling block **106** is coupled to the crown block **104** via a drilling line **108**. In a top drive system (as illustrated), a top drive **110** is coupled to the traveling block **106** and provides the rotational force needed for drilling. A saver sub **112** may sit between the top drive **110** and a drill pipe **114** that is part of a drill string **116**. The top drive **110** rotates the drill string **116** via the saver sub **112**, which in turn rotates a drill bit **118** of a bottom hole assembly (BHA) **119** in a borehole **120** in formation **121**. A mud pump **122** may direct a fluid mixture (e.g., mud) **123** from a mud pit or other container **124** into the borehole **120**. The mud **123** may flow from the mud pump **122** into a discharge line **126** that is coupled to a rotary hose **128** by a standpipe **130**. The rotary hose **128** is coupled to the top drive **110**, which includes a passage for the mud **123** to flow into the drill string **116** and the borehole **120**. A rotary table **132** may be fitted with a master bushing **134** to hold the drill string **116** when the drill string is not rotating.

As described in detail in U.S. Pat. No. 8,517,093, which is incorporated herein by reference in its entirety, various embodiments of downhole tools **136** may be used to produce vibrations in a controlled manner to enable information to be transmitted along the drill string to the surface. The vibrations are generated by controlled impacts between two surfaces. Although shown as positioned behind the BHA **119**, the downhole tool **136** may be part of the BHA **119**, positioned elsewhere along the drill string **116**, or distributed along the drill string **116** (including within the BHA **119** in some embodiments). Using the downhole tool **136**, tunable frequency functionality may be provided that can used for communications as well as to detect various parameters such as rotations per minute (RPM), weight on bit (WOB), and formation characteristics of a formation in front of and/or surrounding the drill bit **118**. By tuning the frequency, an ideal drilling frequency may be provided for faster drilling. The ideal frequency may be determined based on formation and drill bit combinations and the communication carrier frequency may be oscillated around the ideal frequency, and so may change as the ideal frequency changes based on the formation. Frequency tuning may occur in various ways, including physically configuring an impact mechanism to vary an impact pattern and/or by skipping impacts through dampening or other suppression mechanisms.

It is understood that the vibration generation and control functionality provided by the downhole tool **136** may be incorporated into a variety of standalone device configurations placed anywhere in the drill string **116**. These devices may come in the form of agitator variations, drilling sensor subs, dedicated signal repeaters, and/or other vibration devices. In some embodiments, it may be desirable to have separation between the downhole tool **136** and the bottom hole assembly (BHA) for implementation reasons. In some embodiments, distributing the locations of such mechanisms along the drill string **116** may be used to relay data to the surface if transmission distance limits are reached due to increases in drill string length and hole depth. Accordingly, the location of the vibration creation device or devices does not have a required position within the drill string **116** and both single unit and multi-unit implementations may distribute placement of the vibration generating/encoding device throughout the drill string **116** based on the specific drilling operation being performed.

Vibration control and/or sensing functionality may be downhole and/or on the surface **103**. For example, sensing functionality may be incorporated into the saver sub **112** and/or other components of the environment **100**. In some embodiments, sensing and/or control functionality may be provided via a control system **138** on the surface **103**. The control system **138** may be located at the derrick **102** or may be remote from the actual drilling location. For example, the control system **138** may be a system such as is disclosed in U.S. Pat. No. 8,210,283 entitled SYSTEM AND METHOD FOR SURFACE STEERABLE DRILLING, filed on Dec. 22, 2011, and issued on Jul. 3, 2012, which is hereby incorporated by reference in its entirety. Alternatively, the control system **138** may be a stand alone system or may be incorporated into other systems at the derrick **102**. For example, the control system **138** may receive vibration information from the saver sub **112** via a wired and/or wireless connection (not shown). Some or all of the control system **138** may be positioned in the downhole tool **136**, or may communicate with a separate controller in the downhole tool **136**. The environment **100** may include sensors positioned on and/or around the derrick **102** for purposes such as detecting environmental noise that can then be canceled so that the environmental noise does not negatively affect the detection and decoding of downhole vibrations.

Referring to FIG. 1B, one embodiment of a system **140** is illustrated that may be used to create vibrations. The system **140** is illustrated relative to a surface **142** and a borehole **144**. The system **140** includes a vibration generation section **162**, a controller **159**, one or more vibration sensors **158** (e.g., high sensitivity axial accelerometers) for decoding vibrations downhole, and a power section **154**, all of which may be positioned within a drill string **141** that is within the borehole **144**.

The controller **159**, which may also handle information encoding, may be part of a control system (e.g., the control system **138** of FIG. 1A) or may communicate with such a control system. The controller **159** may synchronize dampening timing with impact timing. More specifically, because vibration measurements are being made locally, the controller **159** may rapidly adapt dampening to match changes in vibration frequency and/or amplitude using one or more of the dampening mechanisms described herein. For example, the controller **159** may synchronize the dampening with the occurrence of impacts so that, if the timing of the impacts changes due to changes in formation hardness or other factors, the timing of the dampening may change to track the impacts. This real time or near real time synchronization may ensure that dampening occurs at the peak amplitude of a given impact and not between impacts as might happen in an unsynchronized system. Similarly, if impact amplitude increases or decreases, the controller **159** may adjust the dampening to account for such amplitude changes.

The vibration sensors **158** may be placed within fifty feet or less (e.g., within five feet) of the vibration source provided by the vibration generation section **162**. In the present embodiment, the vibration sensors **158** may be positioned between the power section **154** and the vibration source due to the dampening effect of the rubber that is commonly present in the power section stator. The positioning of the vibration sensors **158** relative to the vibration source may not be as important for communications as for formation sensing, because the vibration sensors **158** may need to be able to sense relatively slight variations in formation characteristics and being closer to the vibration source may increase the efficiency of such sensing. The more distance there is between the vibration source and the vibration sensors **158**, the more likely it is that slight changes in the formation will not be detected. The vibration sensors **158** may include one sensor for measuring axial vibrations for WOB and another sensor for formation evaluation.

The system **140** may also include one or more vibration sensors **146** (e.g., high sensitivity axial accelerometers) positioned above the surface **142** for decoding transmissions and one or more relays **150** positioned in the borehole **144**. The vibration sensors **146** may be provided in a variety of ways, such as being part of an intelligent saver sub that is attached to a top drive on the drill rig (not shown). The relays **150** may not be needed if the vibrations produced by the vibration generation section **162** are strong enough to be detected on the surface by the vibration sensors **146**. The relays **150** may be provided in different ways and may be vibration devices or may use a mud pulse or EM tool. For example, agitators may be used in drill strings to avoid friction problems by using fluid flow to cause vibrations in order to avoid friction in the lateral portion of a drill string. The mechanical vibration mechanism provided by the vibration generation section **162** may provide such vibrations at the bit and/or throughout the drill string. This may provide a number of benefits, such as helping to hold the toolface more stably and maintain consistent WOB.

In some embodiments, a similar or identical mechanism may be applied to an agitator to provide relay functionality to the agitator. For example, the relay may receive a vibration having a particular frequency f, use the mechanical mechanism to generate an alternative frequency signal, and may transmit the original and alternative frequency signals up the drill string. By generating the additional frequency signal, the effect of a malfunctioning relay in the chain may be minimized or eliminated as the additional frequency signal may be strong enough to reach the next working relay.

It is understood that the sections forming the system **140** may be positioned differently. For example, the power section **154** may be positioned closer to the vibration generation section **162** than the vibration sensors **158**, and/or one or more of the vibration sensors **158** may be placed ahead of the vibration generation section **162**. In still other embodiments, some sections may be combined or further separated. For example, the vibration sensors **158** may be included in a mud motor assembly, or the vibration sensors **158** may be separated and distributed in different parts of the drill string **141**. In still other embodiments, the controller **159** may be combined with the vibration sensors **158** or another section, may be behind one or more of the vibration sensors **158** (e.g., between the power section **154** and the vibration sensors **158**), and/or may be distributed.

The remainder of the drill string **141** includes a forward section **164** that may contain the drill bit and additional sections **160**, **156**, **152**, and **148**. The additional sections **160**, **156**, **152**, and **148** represent any sections that may be used with the system **140**, and each additional section **160**, **156**, **152**, and **148** may be removed entirely in some embodiments or may represent multiple sections. For example, one or both of the sections **148** and **152** may represent multiple sections and one or more relays **150** may be positioned between or within such sections.

In operation, the vibration generation section **162** creates vibrations. The vibration sensors **158**, which may be powered by the power section **154**, detect the vibrations for the controller **159**. The controller **159** converts the information contained in the vibrations to digital signals and transmits the digital signals up the drill string using the vibration generation section **162**. The vibrations sent up the drill string are detected by the vibration sensors **146** and decoded to recover the information.

Referring to FIG. **1**C, an environment **180** illustrates one embodiment of the environment **100** of FIG. **1**A from a communications perspective. The environment **180** includes a transmitter (TX) **182** that is coupled to a receiver (RX) **184** via a communication channel **186**. In the present example, the communication channel **186** is the drill string **116** of FIG. **1**A and information is transmitted via elastic waves that pass through the drill string. The elastic waves are generated using controlled impacts, such as are described above. One or more noise sources **188** (e.g., the drilling bit and other equipment, such as a top-drive) may inject noise into the communication channel **186** that affects the transmission of the information.

Referring to FIG. **2**A, a graph **200** illustrates embodiments of a digital signal **202** and a corresponding baseband raw signal **204** plotted against a y-axis **206** representing amplitude and an x-axis **208** representing time in seconds. The amplitude is shown in terms of a bit stream forming the digital signal and so varies from "0" to "1." In some embodiments, the "0" may be viewed as no impact and the "1" may be viewed as full impact from the perspective of controlled impacts.

For purposes of example, the digital signal **202** represents information encoded as a bit stream of 1111100001001100101011111100001 at a bit-rate of 100 Hz. This is the information that is to be transmitted to the surface by a transmitter, such as the transmitter **182** of FIG. **1**C. The baseband signal **204** represents the transmitted form of the digital signal. This is the signal that is generated using controlled impacts, such as are described above. In the present example, the bit stream 1111100001001100101011111100001 is represented by a sequence of delta pulses, which produce an ideal waveform version of the baseband signal **204**.

Ideally, the baseband signal **204** would arrive unaltered at the surface to be decoded, but this does not occur due to factors such as attenuation and reflection. More specifically, various complications exist when attempting to send a signal containing the information along the drill string. For example, the impacts caused by the vibration generation section **162** (FIG. **1**B) create elastic waves that are affected by such factors as attenuation and reflection of the signal at joints of the pipe. Attenuation occurs as the energy in the elastic waves dissipates over distance. Reflection occurs at the joints because the ends of each pipe have threaded joints and the joints have a different mass and cross-section than the pipes. The periodic spatial interval along the drilling string makes information transmission within some frequency bands possible. A higher sampling rate on the receiver side creates an environment in which the original signal spectrum is duplicated. This duplication occurs naturally due to oversampling theory. Rather than discarding or otherwise minimizing this duplicative effect, the present disclosure leverages the duplications on the receiver side to aid in reproducing the original signal.

Referring to FIG. **2**B, a graph **210** illustrates one embodiment of the spectrum amplitude of the digital signal **202** as a curve **212** plotted against a y-axis **214** representing amplitude and an x-axis **216** representing the frequency in Hz.

Referring to FIG. **2**C, a graph **220** illustrates one embodiment of the spectrum amplitude of the baseband signal **204** as a curve **222** plotted against a y-axis **224** representing amplitude and an x-axis **226** representing the frequency in Hz. In the present example, the spectrum curve **212** of FIG. **2**B is duplicated eight times in FIG. **2**C. This is due to the receiver side having a sampling rate that is eight times faster than the transmitting bit-rate, i.e. 800 Hz. Because the signal is duplicated naturally, the faster sampling rate may capture some or all of the duplicated signal curves as illustrated in FIG. **2**C.

As will be described in greater detail below, this duplication means that the some or all of the baseband information may be available in different frequency ranges. This knowledge may in turn be used to select one or more frequency bands that provide a higher quality signal (e.g., that have a better signal to noise ratio (SNR) than other passbands) because any desired frequency bands will likely contain at least a portion of the duplicated baseband signal. If no high quality frequency range is available with the width needed to capture the entire spectrum of the baseband signal, multiple bands can be combined to recover the baseband signal with certain fusion technology.

Referring to FIG. **2**D, a graph **230** illustrates embodiments of a digital signal **232** and a baseband signal **234** plotted against a y-axis **236** representing amplitude and an x-axis **238** representing time. FIG. **2**D illustrates a more realistic example of FIG. **2**A in terms of the waveform shape of the baseband signal **234**.

Referring to FIG. **2**E, a graph **240** illustrates one embodiment of the spectrum of the baseband signal **234** as a curve **242** plotted against a y-axis **244** representing amplitude and an x-axis **246** representing the frequency in Hz. Compared to the ideal curve **222** of FIG. **2**C, the curve **242** clearly illustrates energy decay (e.g., attenuation) along the frequency axis **246**. This difference in the decay between FIGS. **2**C and **2**E occurs because a single pulse generated by the actual impact mechanism is much wider in width than the ideal delta pulse used in FIG. **2**A to create the spectrum of FIG. **2**C. It is noted that although attenuation has affected the amplitude at various frequencies, multiple duplications are still caught by a faster sampling rate of the receiver.

Referring to FIG. **3**, a method **300** illustrates one embodiment of a process that may be used within the environment **180** of FIG. **1**C. The method **300** leverages the existence of the duplicated spectrum, which may be accomplished in various ways. In any given transmission, a single comb filter passband that is part of the frequency characteristics **600** of the drilling pipe communication channel may contain all or part of the baseband spectrum and/or multiple passbands may contain duplicate information. This knowledge may be used to determine how the baseband information should be recovered. For example, a particular passband, such as **602**, **604**, **606**, or **608** in FIG. **6**A, may be selected for demodulation based on one or more desirable criteria exhibited by the passband. Alternatively, multiple passbands may be selected and combined to restore the baseband signal.

Accordingly, in step **302**, the information to be transmitted is encoded by the transmitter **182**. In step **304**, the encoded information is transmitted as a baseband signal through the communication channel **186** (e.g., the drill string) using controlled impacts as described previously. In step **306**, receiver **184** leverages the existence of the duplicate spectrum curves to select one or more adaptive passbands for use in recovering the baseband signal. More specifically, because the transmission is broadband, the receiver can sample at a higher rate than the transmission rate and capture the duplicated baseband spectrum. This enables the receiver to select one or more relatively high quality portions of the broadband signal and still obtain the entire spectrum needed to recover the baseband signal. Alternatively, the receiver can use the entire broadband signal. As will be described below, the passbands may be adapted to compensate for variations within the channel as the variations occur.

Referring to FIG. **4**, a block diagram of one embodiment of a transmitter **400** is illustrated that may be used in an environment such as the environment **180** of FIG. **1**C. In the present embodiment, the transmitter **400** includes an input block **402**, an encoder block **408**, a pilot sequence generation block **410**, a framer block **412**, and an impact mechanism control block **414**. The transmitter **400** is positioned in the borehole and may be located in the downhole tool **136** (FIG. **1**A) or elsewhere (e.g., in another component of the drill string **116**). It is understood that one or more of the components illustrated in FIG. **4** may be located elsewhere (e.g., distributed). Furthermore, while the block diagram of FIG. **4** illustrates basic functionality that may be used to receive, encode, and transmit information, it is understood that one or more of the components may not be considered part of the transmitter **400** in some embodiments.

The input block **402** may include one or more sensors, such as directional sensors **404** and/or gamma sensors **406**, as illustrated in FIG. **4**. The sensors may be positioned anywhere along the drill string as long as they can relay their information to the transmitter **400**. In other embodiments, the input block **402** may not contain sensors, but may receive information from such sensors and/or may receive sensor information from another source. For example, the input block **402** may be configured to receive one or more digital and/or analog streams of information.

The encoder block **408** translates the information from the input block **402** into a bit stream that is to be transmitted. The encoder block **408** may perform various functions, although it is understood that such functions may vary depending on the particular implementation of the encoder block **408**. For example, the encoder block **408** may be configured to avoid long consecutive identical digits (CIDs). As is known, strings of CIDs may create problems in communications systems. By avoiding CIDs, the encoder block **408** can make the timing recovery on the receiver side more robust and simple. As another example, the encoder block **408** may add error detection capabilities with additional parity bits to improve the bit-error rate (BER). In yet another example, the encoder block **408** may shape the spectrum of the baseband signal to make the signal more tolerant to channel variations and additive noise over the channel. Examples of the coding approach used by the encoder block **408** may include, but are not limited to, 6b8b or 8b10.

The pilot sequence generation block **410** is used to periodically inject a pilot sequence (which may also be referred to as a training sequence) into the communication channel (e.g., the drill string). The pilot sequence is sent periodically by the transmitter **400** to help the receiver evaluate the current channel conditions. This will be discussed in greater detail below with respect to the receiver.

The frame block **412** provides defined transmission units and may be used to aid in synchronizing the transmitter **400** with the receiver.

The impact mechanism control block **414** performs the actual transmission process by controlling the impacts created by the vibration generation section **162** (FIG. **1**B) to generate the baseband signal. For example, the impact mechanism control block **414** may allow an impact to occur to transmit a "1" and may prevent or otherwise minimize an impact to transmit a "0." It is understood that the impact mechanism control block **414** may not actually control the actuation of the impact mechanism in some embodiments, but may pass information to another controller that performs the actuation functions. In the present example, the impact mechanism control block **414** includes a valve control **416**.

Referring to FIG. **5**, a block diagram of one embodiment of a receiver **500** is illustrated. In the present embodiment, the receiver **500** includes an input block **502**, a bit rate frequency estimator block **506**, a noise estimator block **508**, a channel selection block **510**, fractionally spaced baseband or band-pass channel equalization blocks **512***a*-**512***c*, spectrum shift blocks **514***a*-**514***c*, a fusion block **516**, a bit timing recovery block **518**, and a decoding block **520**. The receiver **500** is positioned on the surface (e.g., out of the borehole) or between the surface and the transmitter **400** (FIG. **4**). It is understood that one or more of the components illustrated in FIG. **5** may be located elsewhere (e.g., distributed). Furthermore, while the block diagram of FIG. **5** illustrates basic functionality that may be used to receive and decode information, it is understood that one or more of the components may not be considered part of the receiver **500** in some embodiments.

The input block **502** may include one or more sensors, such as velocity sensor **504**, as illustrated in FIG. **5**. The sensor **504** may be positioned anywhere along the drill string or on the surface as long as it can relay its information to the receiver **500**. In other embodiments, the input block **502** may not contain sensors, but may receive information from such sensors and/or may receive sensor information from another source. For example, the input block **502** may be configured to receive one or more digital and/or analog streams of information.

The bit rate frequency estimator block **506** is used to handle possible frequency varying and phase jitter. More specifically, although the baseband bit-rate is known to the receiver **500**, a small amount of instantaneous frequency varying leading to phase shift might still exist. The bit rate frequency estimator block **506** uses the known bit-rate as an approximate frequency reference, a narrow-band filter is turned to 1/T to extract the bit-rate frequency, and then phase aligns to the transitions in the demodulated signal. A digital phase-locked loop (PLL) may be used to produce sampling instants from the demodulated signal that contains interference and additive noise.

The noise estimator block **508** is used to minimize the impact of background noise in the received signal. More specifically, acoustic noise negatively affects the baseband signal. For example, noise from sources such as the drilling bit and the top-drive on the rig are believed to be two major acoustic noise sources. This noise propagates through the drill string and is directly added to the baseband signal, which degrades the quality of the received signal. To counter this signal degradation, the acoustic noise is measured during periods when there is no information being transmitted. Because the measured acoustic noise is unlikely to be in the form of a white distribution (e.g., evenly distributed across a given spectrum) in spite of overall noise power, the power spectral density (PSD) may also be estimated at a selected frequency resolution. The noise PSD helps to evaluate the received signal quality within certain objective frequency bands.

The channel selection block **510** is used to select one or more passbands for demodulation. Inputs to the channel selection block **510** include the input block **502** and the noise estimator block **508**. As described previously, reflections within the drill string create different wave reflections between the pipes and joints result in a comb-filter effect on the propagation of the acoustic wave in the drill string and provide one or more identifiable channels that may be selected as desired frequency bands.

With additional reference to FIGS. **6**A and **6**B, this comb-filter effect results in pass-bands and stop-bands that are interleaved across the spectrum of the received signal. FIG. **6**A illustrates a graph **600** showing the channel unit impulse response in amplitude. The received raw frequency spectrum is illustrated by the graph **610** of FIG. **6**B. In the present example, there are four pass-bands **602**, **604**, **606**, and **608** evident under the 1 kHz frequency point. Due to the duplication characteristic of the oversampled received signal, the same baseband information may be contained in multiple passbands and/or one passband may contain part of the baseband spectrum. Accordingly, two different approaches may be used in channel selection.

One approach involves selecting a single passband as the candidate for demodulation based on the associated SNR that is calculated using the noise level estimated during idle period. For example, the passband containing the most desirable SNR may be selected as long as it is wide enough to contain the needed signal information. The other approach involves selecting multiple passbands and using the information in those passbands to restore the baseband information using a fusion process. It is understood that the second approach may still use SNR as one criterion for selecting a particular passband for the fusion process.

The fractionally spaced channel equalization blocks **512***a*-**512***c* are used to adapt to fluctuations that may occur within a passband. More specifically, within each passband, the power attenuation and phase shift have a certain degree of fluctuation. In the time domain, such fluctuation is demonstrated as inter-symbol interference (ISI) that is related at least partially to the structure of the drill string. The channel equalization blocks **512***a*-**512***c* may also address other factors that may induce destructive interference to the power and/or phase of the received signal at each passband. The channel equalization blocks **512***a*-**512***c* may be used to implement an equalization scheme that is designed to adapt to such channel variations and to eliminate or at least reduce unwanted effects.

More specifically, as described previously, a pilot training sequence is sent periodically by the transmitter **400** to help the receiver **500** evaluate the real time channel situation. The pilot training sequence can be pseudo-random binary signals generated by a linear feedback shift register. The generation scheme of the pilot sequence is known to the receiver **500**, so that the receiver can generate the exact same bit sequence. The channel equalization can be achieved by methods such as, but not limited to, a least mean square estimation algorithm, a recursive least square algorithm, and/or similar methods. The results of equalization produces an adaptive filter for a particular passband. For example, the coefficients of the adaptive filter can be adjusted to minimize the mean square error between the filter output and the known pilot sequence to optimize the passband. The filter coefficients are updated at least as fast as the bit-rate. The equalizer can be realized either at baseband or bandpass. When the training sequence is finished, the equalizer switches to decision directed mode (i.e., using the binary decision output as the desired signal for further fine adaptation). Such a channel estimation procedure can be performed in either the time domain or the frequency domain. Any possible channel slow variations may be tracked by such an adaptive procedure to account for changes as they occur over time.

An adaptive equalizer with the inverse of the channel response can then be applied to the received information stream (e.g., other than the pilot signal). Accordingly, by optimizing each passband using information gained from the pilot signal, the receiver **500** is able to compensate for gain and phase distortions at selected passbands. Ideally, the output of the adaptive filter will be the input to the communication channel.

If a single passband is selected, only a single channel equalization block (e.g., the block **512***b*) may be used. If more than one passband is selected, the equalization procedure can be performed separately for each passband in parallel using the parallel blocks illustrated in FIG. **5**.

The spectrum shift blocks **514***a*-**514***c* are used to relocate a desired spectrum band to DC. It is shifted by a corresponding center frequency that is multiple of 1/T, which is the output of the bit rate frequency estimator block **506**, to place the selected band at DC. In some embodiments, a low-pass filter with the cut-off frequency set at 1/(2T) may be applied to remove other unwanted high frequency components.

The fusion block **516** is used to combine multiple passbands (if selected). More specifically, a fusion process is applied to combine filtered passbands. The fusion process can use, but is not limited to, a maximum ratio combination (MRC) algorithm that applies different gains to each passband and then sums the passbands together. The fusion gains can be obtained using the SNR of each passband so that passbands with higher quality received signals contribute more to the final fusion output than passbands with lower quality signals.

The bit timing recovery block **518** provides a timing synchronization scheme. It is used to provide a correct timing to sample the equalizer **514***b* output or fusion block output **516**. Using the output from PLL inside bit-rate estimation block **506** as a reference and benefitting from the encoder inside the transmitter **400**, the peak of each base band signal pulse can be sampled at the precise time instants.

The decoding block **520** corresponds to the encoder block **408** on the transmitter side and performs decoding to translate the bit stream back to the information bit stream.

Referring to FIG. **7** and with additional reference to FIGS. **8**A and **8**B, a method **700** illustrates one embodiment of a process that may be used with the transmitter **400** of FIG. **4**. FIGS. **8**A and **8**B illustrate graphs of embodiments of waveforms that correspond to particular steps of the method **700**.

In step **702**, a determination may be made as to whether a pilot signal should be transmitted. For example, the determination may include such factors as how long it has been since the pilot signal was last transmitted and/or whether there is currently other information to be transmitted. The pilot signal may generally be transmitted only when other information is not being transmitted. In some embodiments, the transmission of other information may be interrupted for the pilot signal, particularly if a defined period of time has elapsed.

If the determination of step **702** indicates that the pilot signal is to be transmitted, the method **700** continues to step

704. In step **704**, the pilot signal is framed. In step **706**, the pilot signal is transmitted via impact control as previously described. It is understood that, in some embodiments, the transmitter **400** may not perform the impact control process, but may instead send the framed pilot signal to another system that controls the actual impact process. The method **700** then returns to step **702**.

If the determination of step **702** indicates that no pilot signal is to be transmitted, the method **700** continues to step **708**. In step **708**, a determination may be made as to whether there is information (e.g., other than the pilot signal) to be transmitted. If the determination of step **708** indicates that there is no information to be transmitted, the method **700** returns to step **702**.

If the determination of step **708** indicates that there is information to be transmitted, the method **700** moves to step **710**. In step **710**, the information is encoded. The method **700** then continues through steps **704** and **706** to transmit the encoded information. This is shown in graph **800** of FIG. **8**A with embodiments of an encoded digital waveform **802** that is to be transmitted and the corresponding baseband waveform **804** that is actually transmitted. FIG. **8**B illustrates a graph **810** that shows an embodiment of the spectrum amplitude **812** of the transmitted baseband waveform **804**.

Referring to FIG. **9** and with additional reference to FIGS. **10**A and **10**B, a method **900** illustrates one embodiment of a process that may be used with the receiver **500** of FIG. **5**. FIGS. **10**A and **10**B illustrate graphs of embodiments of waveforms that correspond to particular steps of the method **900**.

In step **902**, a determination is made as to whether information has been received via the drill string. If the determination of step **902** indicates that no information has been received, the method **900** moves to step **904**. In step **904**, the acoustic noise may be measured across the frequency range of interest. In step **906**, the power spectral density may be calculated based on the measured acoustic noise. The PSD may be used later during channel selection. The method **900** then returns to step **902**. It is understood that a timer or other trigger may be checked before steps **904** and **906** are performed to prevent the method from constantly looping through steps **904** and **906** whenever no information has been received.

If the determination of step **902** indicates that information has been received, the method **900** moves to step **908**. In step **908**, a determination is made as to whether the information is a pilot signal. The determination of the pilot signal can be performed by calculating the cross-correlation function. If the determination of step **908** indicates that the information is a pilot signal, the method **900** moves to step **910**.

In step **910**, one or more spectrum bands are selected based on criteria such as signal to noise ratio. The noise power of the interested spectrum band is obtained from step **904**. With the desired spectrum bands selected, the method **900** moves to step **912**.

In step **912**, the method **900** uses the pilot signal to determine the channel responses for one or more channels. The channel responses are taken into account by, for example, modifying adaptive filtering coefficients if needed. The method **900** then returns to step **902**.

If the determination of step **902** indicates that information has been received and the determination of step **908** indicates that the information is not a pilot signal, the method **900** moves to step **914**. Graph **1000** of FIG. **10**A illustrates an embodiment of the raw waveform **1002** of the received signal and graph **1010** of FIG. **10**B illustrates an embodiment of the raw spectrum amplitude **1012** of the received signal, which varies from the spectrum amplitude **812** of the transmitted signal of FIG. **8**B due to the non-ideal channel conditions.

In step **914**, one or more spectrum bands are selected based on the decision made by step **909** to use in recovering the baseband signal. For purposes of example, this desired frequency band is located around 400 Hz (e.g., four times of the transmission bit rate) in the spectrum amplitude **1012** of FIG. **10**B. In step **916**, signal processing (e.g., decision directed equalization, spectrum shifting, and/or filtering) is performed to recover the baseband signal. One embodiment of step **916** is described in greater detail below with respect to FIG. **11**. In step **918**, the baseband signal is decoded to recover the information bit stream that it contains. The method **900** then returns to step **902**.

Referring to FIG. **11** and with additional reference to FIGS. **12**A and **12**B, a method **1100** illustrates one embodiment of a process that may be used for step **916** of FIG. **9**. FIGS. **12**A and **12**B illustrate graphs of embodiments of waveforms that correspond to particular steps of the method **1100**.

In step **1102**, a baseband or passband linear equalization process is performed by the channel equalization blocks **512***a*-**512***c* as described with respect to FIG. **5**. In step **1104**, the spectrum **1012** of FIG. **10**B may be shifted to center the selected band on DC, as shown in graph **1200** of FIG. **12**A. The spectrum amplitude **1203** is the shifted version of the equalized signal. In step **1106**, frequency response filtering may be performed to isolate the passband as shown in FIG. **12**A with filter frequency response **1202**. The filtering results in a time domain waveform **1212** of the baseband signal as shown in graph **1210** of FIG. **12**B. The time domain waveform **1212** can be converted to its digital equivalent waveform **1214**.

Referring to FIG. **13**, one embodiment of a computer system **1300** is illustrated. The computer system **1300** is one possible example of a system component or device such as the control system **138** of FIG. **1**A. In scenarios where the computer system **1300** is on-site, such as within the environment **100** of FIG. **1**A, the computer system may be contained in a relatively rugged, shock-resistant case that is hardened for industrial applications and harsh environments. It is understood that downhole electronics may be mounted in an adaptive suspension system that uses active dampening as described in various embodiments herein.

The computer system **1300** may include a central processing unit ("CPU") **1302**, a memory unit **1304**, an input/output ("I/O") device **1306**, and a network interface **1308**. The components **1302**, **1304**, **1306**, and **1308** are interconnected by a transport system (e.g., a bus) **1310**. A power supply (PS) **1312** may provide power to components of the computer system **1300**, such as the CPU **1302** and memory unit **1304**. It is understood that the computer system **1300** may be differently configured and that each of the listed components may actually represent several different components. For example, the CPU **1302** may actually represent a multi-processor or a distributed processing system; the memory unit **1304** may include different levels of cache memory, main memory, hard disks, and remote storage locations; the I/O device **1306** may include monitors, keyboards, and the like; and the network interface **1308** may include one or more network cards providing one or more wired and/or wireless connections to a network **1314**. Therefore, a wide range of flexibility is anticipated in the configuration of the computer system **1300**.

The computer system **1300** may use any operating system (or multiple operating systems), including various versions of operating systems provided by Microsoft (such as WINDOWS), Apple (such as Mac OS X), UNIX, and LINUX, and may include operating systems specifically developed for handheld devices, personal computers, and servers depending on the use of the computer system **1300**. The operating system, as well as other instructions (e.g., software instructions for performing the functionality described in previous embodiments) may be stored in the memory unit **1304** and executed by the processor **1302**. For example, if the computer system **1300** is the control system **138**, the memory unit **1304** may include instructions for performing the various methods and control functions disclosed herein.

It will be appreciated by those skilled in the art having the benefit of this disclosure that this system and method for causing, tuning, and/or otherwise controlling vibrations provides advantages in downhole environments. It should be understood that the drawings and detailed description herein are to be regarded in an illustrative rather than a restrictive manner, and are not intended to be limiting to the particular forms and examples disclosed. On the contrary, included are any further modifications, changes, rearrangements, substitutions, alternatives, design choices, and embodiments apparent to those of ordinary skill in the art, without departing from the spirit and scope hereof, as defined by the following claims. Thus, it is intended that the following claims be interpreted to embrace all such further modifications, changes, rearrangements, substitutions, alternatives, design choices, and embodiments.

What is claimed is:

1. A method for use with a drill string positioned within a borehole, the method comprising:

receiving, by a receiver, a baseband signal transmitted via vibrations through the drill string using a plurality of elastic waves;

oversampling the received baseband signal at the receiver to duplicate a spectrum of the baseband signal a plurality of times,

determining whether a single passband of a plurality of available passbands has a predetermined signal to noise ratio and sufficient bandwidth to include an entire spectrum of the baseband signal of one of the plurality of spectrums of the baseband signal created by the oversampling;

selecting, by the receiver, if the single passband is available, the single passband from the plurality of passbands that are caused by the reflection of the baseband signal within the drill string based on one of the plurality of passbands having the predetermined signal to noise ratio and sufficient bandwidth to include the entire spectrum of the baseband signal of one of the plurality of spectrums of the baseband signal created by the oversampling, in order to recover the baseband signal from the duplicated spectrum;

selecting, by the receiver if the single passband is not available, multiple passbands from the plurality of passbands including different portions of the spectrum of the baseband signal;

combining portions of the spectrum of the baseband signal recovered from each of the selected multiple passbands to recover the entire spectrum of the baseband signal, the combination based upon a signal to noise ratio of each of the passbands, such that higher quality passbands contribute more to the combination than the passbands with lower quality signals; and

decoding, by the receiver, the baseband signal to recover a bit stream contained within the baseband signal.

2. The method of claim **1** further comprising:

measuring acoustic noise when no signal is being received;

estimating a noise power spectral density using the measured acoustic noise; and

using the noise power spectral density to find the signal to noise ratio.

3. The method of claim **1** wherein the multiple passbands contain overlapping portions of the baseband signal due to the duplicated spectrum.

4. The method of claim **1** wherein each of the multiple passbands is selected based on at least one of a signal to noise ratio of the passband or a width of the passband.

5. The method of claim **1** further comprising calculating a weight for each of the multiple passbands based on a signal to noise ratio of the passband for which the weight is being determined, wherein the weight calculated for each passband determines how that passband is used when combining portions of the baseband signal.

6. The method of claim **1** further comprising identifying the plurality of available passbands.

7. The method of claim **1** further comprising:

receiving a pilot training signal from a transmitter that is responsible for generating the baseband signal within the drill string;

determining a channel response within the at least one passband based on the pilot signal; and

equalizing a waveform obtained via the at least one passband using the channel response.

8. The method of claim **7** wherein multiple passbands are selected from the plurality of available passbands, and wherein the steps of determining a channel response and equalizing the passband are performed for each of the multiple passbands.

9. The method of claim **1** further comprising sampling the baseband signal at a rate that is a multiple of a rate at which the baseband signal was transmitted.

10. A method for use with a drill string positioned within a borehole, the method comprising:

receiving, by a receiver, a pilot signal transmitted through the drill string via vibrations using a first plurality of elastic waves;

modifying, by the receiver, an adaptive filter corresponding to at least one passband to compensate for variances between the received pilot signal and a known pilot signal;

receiving, by the receiver, a baseband signal transmitted through the drill string using a second plurality of elastic waves;

equalizing, by the receiver, the baseband signal using the adaptive filter to form a corrected baseband signal;

oversampling the received baseband signal at the receiver to duplicate a spectrum of the baseband signal a plurality of times,

determining whether a single one of a plurality of available passbands has a predetermined signal to noise ratio and sufficient bandwidth to include an entire spectrum of the baseband of the plurality of spectrums of the baseband signal created by the oversampling signal;

selecting, by the receiver, when the single passband is available, the single passband from the plurality of passbands that are caused by the reflection of the baseband signal within the drill string based on one of the plurality of passbands having the predetermined signal to noise ratio and sufficient bandwidth to include the entire spectrum of the baseband signal of the plurality of spectrums of the baseband signal created by the oversampling, in order to recover the baseband signal from the duplicated spectrum;

selecting, by the receiver if the single passband is not available, multiple passbands from the plurality of passbands;

combining portions of the spectrum of the baseband signal recovered from each of the multiple passbands to recover the entire spectrum of the baseband signal, the combination based upon a signal to noise ratio of each of the passbands, such that higher quality passbands contribute more to the combination than the passbands with lower quality signals; and

decoding, by the receiver, the baseband signal to recover a bit stream contained within the baseband signal.

11. The method of claim **10** wherein modifying the adaptive filter includes adjusting coefficients of the adaptive filter to minimize a mean square error between the received pilot signal and the known pilot signal.

12. A receiver for use in borehole communications comprising:

an input block configured to receive a plurality of duplicates of at least a portion of a spectrum of a baseband signal, the baseband signal includes a bit stream transmitted through a drill string positioned in a borehole via vibrations, the plurality of duplicates, caused by oversampling of the received baseband signal;

a channel selector configured to determine whether a single one of plurality of passbands has a predetermined signal to noise ratio and sufficient bandwidth to include the entire baseband signal of the plurality of spectrums of the baseband signal created by the oversampling, to select, if a single passband is available, the single passband from the plurality of passbands for use in recovering the baseband signal based on one of the plurality of passbands have the predetermined signal to noise ratio and the sufficient bandwidth to include the entire spectrum of the baseband signal of the plurality of spectrums of the baseband signal created by the oversampling, wherein the channel selector is configured to use the existence of the duplicates to select multiple passbands including different portions of the spectrum of the baseband signal from the plurality of available passbands if the single passband is not available to contain the entire spectrum of the baseband signal of the plurality of spectrums of the baseband signal created by the oversampling;

a fusion circuit for combining portions of the spectrum of the baseband signal recovered from each of the selected multiple passbands to recover the entire spectrum of the baseband signal, the combination based upon a signal to noise ratio of each of the passbands, such that higher quality passbands contribute more to the combination than the passbands with lower quality signals; and

a decoder configured to recover the bit stream from the baseband signal.

13. The receiver of claim **12** further comprising a channel equalizer configured to compensate for variances in the at least one passband based on differences between a known pilot signal and a received pilot signal.

14. The receiver of claim **12** further comprising a bit timing recovery block configured to provide frequency jitter correction information to the decoder.

15. The receiver of claim **12** further comprising an acoustic noise block configured to provide acoustic noise information to the channel selector for signal to noise ratio calculations.

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